Energy Choice Matters
September 30, 2009

Md. PSC Invites Proposals for Long-Term Supply Contracts, New Generation

The Maryland PSC opened a new proceeding (Case 9214) to investigate whether it should exercise its authority to order electric utilities to enter into long-term contracts to anchor new generation, or to construct, acquire, or lease and operate new electric generating facilities in Maryland.

The Commission was responding to a petition from CPV Maryland which had sought a Commission order directing the utilities to enter into long-term PPAs with its St. Charles facility (Matters, 8/12/09).

The PSC concluded that its examination of whether Maryland needs new generating facilities should not be limited to CPV's proposal, and further said that the examination should occur separately from its ongoing SOS procurement review in Case 9117.

The Commission noted that, as part of its statutory obligation to oversee the procurement of Standard Offer Service for residential and small commercial customers, it may, "require or allow an investor-owned electric company to construct, acquire, or lease, and operate, its own generating facilities, and transmission facilities necessary to interconnect the generating facilities with the electric grid, subject to appropriate cost recovery," per § 7-510(c)(4)(ii)(6) of the Public Utility Companies Article (PUC), Annotated Code of Maryland. The Commission may also, "require or allow an investor-owned electric company to procure electricity for [residential and small commercial customers] directly from an electricity supplier through one or more bilateral contracts outside the competitive process," per PUC § 7-510(c)(4)(ii)1.B.

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Revised Conn. DPUC Draft Would Not Require RFPs for Long-Term Contracts

A revised Connecticut DPUC draft decision would allow electric distribution companies (EDCs) to procure long-term contracts for Standard Service outside of a competitive RFP process, relaxing a requirement contained in an earlier proposed order.

As only reported by *Matters*, the original draft would have required any long-term contract to be procured through an RFP (Only in Matters, 9/2/09).

"While the Department believes that an RFP is the most appropriate procurement option, other offers could provide benefits to customers, and should not be excluded at this point," the revised draft sates. Connecticut Light and Power had petitioned the DPUC to lift the RFP requirement.

"However, the EDCs will be required to meet a high standard to ensure that long-term contracts recommended outside of an RFP process will provide benefits to customers that generally exceed those of other available options," the draft continues.

Given the impending review of the EDC's current procurements, "the EDCs should investigate options outside of RFPs after initial long-term contract proposals have been reviewed," the draft says.

Furthermore, if an EDC affiliate will bid into an RFP process, or will be the counterparty to a bilateral contract negotiated outside an RFP, the draft would require the EDC to use separate buy and sell teams throughout the process. "Before soliciting affiliate bids, an EDC must first seek

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MXenergy Reports Hedging Limits Under New Sempra Agreement

Fixed price hedges under MXenergy's new hedging agreement with Sempra Energy Trading will be limited to a contract length term of 24 months, MXenergy said in an SEC filing (Only in Matters, 8/21/09). In addition, the fixed price portfolio of hedges is limited to a weighted average volumetric tenor not to exceed 14 months in duration.

With regards to MXenergy's fixed price customer mix, MXenergy may not, during any 12 month period, enter into any new fixed price contracts with respect to the gas business where the residential customer equivalents of such contracts are greater than 75% of all residential customer equivalents of all new contracts entered into during such period and/or maintain a customer portfolio with more than 325,000 residential customer equivalents operating under fixed price contracts.

In connection with the Sempra hedge facility, the aggregate notional exposure amount of fixed price hedges allowed to be entered into under the facility is limited to $260.0 million, without adjustment for mark to market movements thereafter.

Additionally, in reporting that its annual 10-K will be delayed due to its recent restructuring and board recomposition, MXenergy said that it expects that its consolidated statements of operations for the year ending June 30, 2009, will reflect a net loss of approximately $95 million to $105 million, as compared with net income of $24.8 million for the prior fiscal year. The preliminary figures are estimated and unaudited.

MXenergy said that volatility in natural gas and electricity commodity prices resulted in significant negative fair value adjustments to derivative instruments utilized as economic hedges during fiscal year 2009. Unrealized losses from risk management activities, which are non-cash items, are expected to be approximately $85 million to $90 million for fiscal year 2009, as compared with unrealized gains of $67.2 million for the prior fiscal year.

Interest expense (net of interest income) is expected to increase approximately $10 million to $12 million during fiscal year 2009, as compared with the prior fiscal year, primarily as a result of incremental interest and fees associated with numerous amendments to MXenergy's primary credit and hedge facilities during fiscal year 2009. These facilities were subsequently replaced in the restructuring.

Reserves and discounts, which include the provision for doubtful accounts, are expected to increase approximately $7 million to $9 million for fiscal year 2009, as compared with the prior fiscal year, due to: (1) higher revenues in MXenergy's non-POR markets; (2) deterioration in the aging of customer accounts receivable and higher charge-off experience in certain non-POR markets; and (3) higher contractual discounts in markets where utilities guarantee MXenergy's customer accounts receivable.

Mich. PSC Restricts End User Participation in RTO Markets Pending Investigation

The participation of Michigan retail customers in any regional transmission organization wholesale market has been temporarily restricted during the pendency of a Michigan PSC investigation into demand response rules, such that, "only LSEs within Michigan [shall] be allowed to aggregate retail customers to whom they supply electric retail supply service for RTO wholesale market participation," until further Commission order (Only in Matters, 8/18/09). Direct participation or participation through non-LSE providers is prohibited until further order.

As only reported in *Matters*, several utilities including Detroit Edison and Consumers Energy had petitioned the PSC for the restriction and accompanying investigation, claiming that direct customer participation in RTO wholesale markets could financially harm non-participating customers.

The Commission was, "persuaded that the relief requested by the Electric Utilities should be granted," and opened an investigation into the appropriate rules and regulations for the direct participation of Michigan retail customers in an RTO wholesale market (U-16020). The investigation will also review whether licensing regulations should be adopted for Load Modifying Resources and Aggregators of Retail Customers.

Michigan Adopts Final Rules to Implement Choice Cap

Michigan alternative electric suppliers (AES) will be allowed to request a list of their customers organized by the customer's classification into one of five choice groupings, the Michigan PSC ruled in implementing the 10% cap on competitive electric sales.

Constellation NewEnergy had requested that suppliers be informed of which grouping each of their customers is in (Only in Matters, 9/11/09).

The Commission's final rule largely tracks its original proposal and consensus items from a working group which establish procedures to assign customers allotments under the choice cap (Matters, 8/26/09). Among other things, the final order affirms that once a customer is allotted space under the choice cap, that customer may not be forced back to bundled utility service, regardless of whether the cap decreases in subsequent years. The Commission also ordered the utilities to develop an online cap-tracking system updated monthly, weekly, or daily depending on the level of choice sales.

As noted in our August story on the proposed rules, there are five customer groupings establishing different rights and abilities to take competitive service for new and expanded load (see full breakdown in our 8/26 story). The Commission affirmed those grouping yesterday, declining to further clarify Group Three and Group Four customers as requested by Consumers Energy. Group Three customers have, "existing load and subsequent increased load through meters served continuously by an AES since October 6, 2008." Group Four customers are those customers, "seeking to expand usage at a facility served through an AES where expand means to connect new load through an existing meter." The PSC explained that after expanding, a Group Four customer becomes a Group Three customer for the purposes of the next round of annual choice allotments. "While, the Commission readily concedes that confusion is possible regarding the distinction between Groups Three and Four, there does not appear to be any better way to explain the distinction," the Commission said.

The Commission also held that an individual customer, and its supplier, shall be able to contact the utility to determine the customer's choice Group status.

Responding to concerns raised by Constellation, the Commission held that while utilities will have 60 days to implement the cap tracking system approved by the Commission yesterday, the Commission expects Detroit Edison, "to take appropriate steps to ensure that choice requests are handled appropriately and without disruption," during the interim period, should choice load dramatically increase prior to the tracking system's implementation. Constellation had raised concerns about the flow of information and ability of suppliers to manage customer expectations if Detroit Edison nears the 10% cap prior to the introduction of the tracking system.

The Commission dismissed, however, Constellation's concerns about the form letter used by utilities to notify customers about the cap, as Constellation had requested that the Commission order the utilities to clarify their letters to state that customers cannot be forced back onto bundled service once they have received an allotment under the choice cap. The Commission said that the content of specific utility form letters is outside the scope of the proceeding, and said Constellation may bring a complaint before the Commission regarding any letter if it so chooses. Still, the Commission said that it, "has an expectation that all utility or AES communications should accurately reflect the new procedures adopted today."

The Commission's order provides a clarification requested by Energy Michigan, holding that a customer's energy allotment under the cap is defined as the level of megawatt-hours assigned to a customer based on its actual purchases during the most recent calendar year. A draft definition had said that the allotment would be based on "customer sales," but Energy Michigan had noted that the customer purchases, and does not sell, electricity.

The PSC also specified that the notification informing customers of assignment of an energy allotment under the cap shall occur through telephone or e-mail.

The 10% cap will be based on a utility's preceding calendar year sales, defined as the level of megawatt-hours sold from January through December of the prior year, including retail access sales. Each utility shall calculate its preceding calendar year sales using the methodology provided for in the utility's Power Supply Cost Recovery 45-day report. The Commission denied Constellation's argument that retail choice sales which existed prior to the cap should be excluded from the preceding calendar year sales in setting the cap.

The Commission denied Consumers' request that a rule be added directing utilities to inform Group Three, Four and Five customers of their allocation status for the annual allocation period prior to February 1 of each annual allocation period. The Commission found that, "[t]he suggestion falsely assumes that all allotments will come along at the beginning of the year, which surely will not take place," the PSC said.

The PSC also rejected Consumers' request for 60 days to file its preceding calendar year sales, as the Commission noted that, "[i]t can hardly be claimed by Consumers that it is a surprise that the utility will need to calculate the level of its preceding calendar year sales, its weather adjusted retail sales for the preceding calendar year and the resulting cap."

"There is no reason for the calculation of these items and the assembly of supporting documentation to take 60 days," the Commission said in requiring the data to be submitted within five days.

Abacus Energy Acquires Always Electric

Always Electric, recently certified but yet to serve customers in ERCOT, reported that it is under new ownership after a transaction with Abacus Energy, Always said in applying for a REP certificate amendment at the PUCT.

Always received its REP certificate in April and was held by principals of vendor ePsolutions (Matters, 3/18/09).

Abacus had previously applied for a REP certificate but was denied a certificate without prejudice for a deficient application (Only in Matters, 5/19/09). Among other reasons, Abacus did not submit information showing it met new PUCT financial standards.

As previously reported, Abacus President Omer Varol owns and runs Callax Telecom Holding GmbH, which is a multi-million dollar German telecom, advertising, mobile telephone, and electric provider. Varol also has interests in U.S. telecom firms in various fields (such as interexchange service).

Varol is now President of Always Electric as well.

John Landry, Abacus Senior Vice President, has assumed the same role at Always Electric. Landry was previously COO at Glacial Energy, and also had stints at Catalyst Natural Gas and NewEnergy Associates.

Abacus will use ePsolutions for EDI, billing and other backoffice services.

Direct Access Coalition Opposes Inclusion of Dynamic Pricing Costs in PG&E Delivery Rates

Pacific Gas & Electric should not be allowed to transfer costs to implement dynamic pricing for bundled customers to a distribution charge imposed on all customers, the Direct Access Customer Coalition said in a brief before the California PUC (A.09-02-022).

PG&E has applied to record in the Dynamic Pricing Memorandum Account the incremental costs it incurs through December 2010 to implement dynamic pricing and, upon approval of its application, transfer the recorded balance from the Dynamic Pricing Memorandum Account to the Distribution Revenue Adjustment Mechanism for subsequent recovery in distribution rates.

"Since the proposed dynamic pricing programs do not benefit [direct access] customers or the energy service providers ('ESPs') who serve them, the costs PG&E incurs to implement dynamic pricing should be recovered solely from PG&E's bundled service customers," the Direct Access Customer Coalition said.

Aside from direct access customers not being eligible for dynamic pricing offered by PG&E, the Coalition noted that bundled service dynamic pricing is meant to reduce bundled generation demand on peak days, a benefit which accrues only to bundled service customers since competitive providers manage their own supply portfolios to address their customers' peak needs.

"Given that PG&E competes with the ESPs

that serve direct access customers on its system, it is hardly surprising that it is attempting to pass on to its competitors' customers the costs of the dynamic pricing program. However, it would be an injustice should the Commission assent to this cost-shifting," the Coalition added.

Other customer groups such as the California Large Energy Consumers Association support the Coalition's position.

TURN and the Division of Ratepayer Advocates, however, support PG&E's cost allocation, with DRA arguing that system-wide reliability benefits from dynamic pricing compel placing costs in distribution rates.

FERC Approves CAISO Changes to Start-Up/Minimum Load Offers

FERC accepted without modification the California ISO's proposal to allow for more frequent updates to generators' start-up (SU) and minimum load (ML) offers, to reflect higher "wear and tear" costs associated with increased run times (ER09-1529, Matters, 8/24/09).

Under the approved proposal, generators may change start-up and minimum load costs under the Registered Cost option from once in a six-month period to once every thirty days. FERC agreed that the changes, "will provide resource owners the needed flexibility to choose the option that best enables recovery of their start-up and minimum load costs, including costs incurred due to environmental limitations and wear and tear on units from frequent start-ups." FERC also found that CAISO's proposal includes sufficient safeguards to ensure that such costs are not over-compensated.

To mitigate market power concerns, FERC accepted CAISO's petition to reduce the cap on Registered Cost option costs in Non-Local Capacity Areas from 400% of the Proxy Cost to 200% of the Proxy Cost. The Commission denied protests from the Western Power Trading Forum regarding the level of mitigation.

"Given the market monitor's concern that increasing the frequency with which generators may switch between bid options also increases the risk of market manipulation, we find that lowering the bid adder for resources outside of load pockets reasonably mitigates the risk that a bid-switching generator could exercise market power," FERC said. FERC, however, also denied requests for additional mitigation from the California PUC.

FERC rejected requests for a sunset date for CAISO's proposal, although the Commission stressed that CAISO and its market monitor should carefully assess the impact of the interim solution on the markets.

Briefly:

PUCT Opens Docket to Review EFLs, TOS

The PUCT has docketed Project 37500 for the "Review of Electricity Facts Labels and Terms of Service Documents."

Good Energy L.P. Applies for Pa. License

Good Energy L.P. applied for an electric aggregator and broker/marketer license at the Pennsylvania PUC to serve all sizes of non-residential customers in all service areas.

Conn. DPUC Tweaks IRP Draft

The Connecticut DPUC released a revised draft of its 2009 integrated resource plan in docket 09-05-02 that tweaks its discussion of several areas, but does not reach any materially different conclusions than its earlier draft as covered in our 9/2/09 story. The revised draft still finds that no new generation (renewable or otherwise) or demand-side resources are needed.

Prier Energy Adds Trade Names

The PUCT approved Prier Energy's application to add the trade names General Power & Light and Todays Energy to its REP certificate (Only in Matters, 9/10/09).

Power Tree Seeks Texas Aggregation License

Power Tree Inc. applied for an aggregation certificate at the PUCT to pool residential, commercial and industrial customers.

FERC Approves NIPSCO-Edison Mission Agreement

FERC accepted a transmission upgrade cost allocation agreement among Northern Indiana Public Service Company, Edison Mission Marketing & Trading, PJM and the Midwest ISO under which Edison will provide phased funding of certain breaker upgrades and transmission upgrades to NIPSCO's facilities (Matters, 7/30/09). NIPSCO will pay for other related upgrades. The upgrades are meant to address operating constraints first raised by NIPSCO in its complaint in FERC Docket No. EL05-103. With the agreement, the RTOs will not need to develop a cost allocation methodology between them to address the subject operational upgrades, and no costs will be allocated to their market participants.

Michigan Approves SEMCO, Michigan Gas Utilities GCRs

The Michigan PSC approved a base gas cost recovery (GCR) factor of $7.3231 per Mcf at Michigan Gas Utilities for the 12-month period ending March 31, 2010. The PSC also approved a base GCR factor of $7.8394 per Mcf at SEMCO Energy Gas Company for the 12-month period ending March 31, 2010.

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The PSC invited all parties interested in making proposals for new Maryland-located electric generating facilities pursuant to PUC §§ 7-510(c)(4)(ii)(6) or 7-510(c)(4)(ii)1.B to file such proposals with the Commission in Case 9214. The proposals should address the following factors, at a minimum: the location of the proposed facility, the number of megawatts to be produced, the type of generation technology to be utilized, the Commercial Operations Date, and for long-term contracts, the contract length, the Commission said.

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approval of the Department, and will be required to demonstrate that safeguards will be implemented to ensure against favoritism," the draft holds.

The draft would also clarify that the 20% cap on bilaterally sourced Standard Service supplies would apply to 20% of eligible Standard Service load, rather than 20% of load currently on Standard Service. Retail suppliers have said that basing the calculation on eligible Standard Service load will increase risks of stranded costs, given the increasing migration rates in Connecticut.

The revised draft also clarifies that the intent of the bilateral procurements is to, "lower the cost of Standard Service power over the term of the contract when compared to the forecasted cost of Standard Service absent the procurement." Wording in the initial draft had concerned the Office of Consumer Counsel by suggesting only contracts that were lower than current market prices at the time of procurement would be approved, forestalling, OCC said, the ability to procure contracts which could reduce volatility.

The updated draft would also expand confidentiality protections for two to five-year energy-only contracts procured under the bilateral process, by adopting the same confidentiality provisions for such contracts as currently established for full requirements Standard Service procurements. For broader procurements that may take up to six weeks to approve, the Department will allow a general description of the bids, except for the name of the bidder, to be disclosed to the public during the course of the proceeding, and held that other elements regarding confidentiality contained in the previous draft will also apply.

The new draft would require all counterparties to long-term contracts to provide performance assurances and adequate credit support to back those assurances, answering a concern raised by retail suppliers.